PG&E's Integrated Resource Plan

Summary of Long-Term Plan

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I. Introduction

PG&E seeks approval of its demand forecast for the period 2005 through 2014 and its resource procurement strategy to meet the defined resource needs. Additionally, PG&E seeks that the Commission grant it authority to execute contracts for resource procurement with term duration of 5 years or less, and approve expenditures for proposed Energy Efficiency programs through 2008. This procurement can only occur if PG&E has reasonable assurances for full and timely cost recovery of procurement under this plan, provided for by a Commission extension of the AB57 trigger mechanism (codified as Section 454.5 of the Public Utilities Code).

PG&E advises the Commission that as part of its resource plan it is currently undertaking a competitive solicitation for renewable resources pursuant to R.04-04-026, and has initiated the process for two competitive procurement solicitations to meet its minimum defined long-term requirements. PG&E anticipates that long-term contracts resulting from these procurement solicitations will be submitted to the Commission for contract approval and rate recovery through compliance filings.

The plan is the culmination of the process defined by the Commission and used assumptions outlined by the Commission in its June 4, 2004 Assigned Commissioner's Rulings (ACR) and June 16 and June 29, 2004 Administrative Law Judge's Rulings. The result of this process is the identified need for additional energy and capacity resources throughout the forecast horizon, along with the strategy to meet these resource requirements.

PG&E's plan will allow it to procure capacity and energy products to meet the identified requirements, and is wholly consistent with the State's Energy Action Plan "loading order" for additional resources. The plan includes aggressive implementation of energy efficiency and demand response programs, shows how renewable resources can meet the Renewable Portfolio Standard target of 20% by 2010 under the Medium Load Case, and clean and efficient conventional generation to meet remaining load requirements. PG&E proposes to procure resources primarily through competitive solicitation in order to stimulate the power market in California and ensure the lowest cost procurement is achieved.

II. Resource Planning Methodology and Assumptions

PG&E employed a comprehensive and dynamic process in developing its preferred resource portfolio using current and appropriate assumptions, much of which came from publicly-available CEC data. PG&E considered a range of portfolio resource options in order to develop cost-effective and reasonable resource plans and ensure the preferred portfolio met the requirements of a range of scenarios required in the Commission's June 4, 2004 ACR.

In developing the portfolios discussed below, PG&E used several criteria to test candidate portfolios to ensure they met requirements and were sufficiently adaptable to be workable under a range of potential conditions, including the ability to accommodate a range of market structure outcomes, customer demand, regulatory changes such as acceleration of resource adequacy targets, and gas price volatility. PG&E also estimated the carbon dioxide (CO_2) emissions of the preferred portfolio to assess future risk when CO_2 becomes regulated.

a. Planning Methodology

PG&E developed three resource portfolios, corresponding to the three load forecasts defined by the commission in the June 4, 2004 ACR. All portfolios were designed to meet several criteria, including meeting and maintaining resource adequacy requirements through the planning horizon, achieving mandated renewable resource procurement targets, minimizing the risk of stranded costs in the future, increasing resource diversity to reduce fuel risks. Portfolios were also analyzed for their environmental attributes and carbon emissions.

The "Preferred" portfolio was then measured against several additional metrics to ensure it was sufficiently flexible to respond to changes in the economic and operating environment. These metrics include estimated impact on ratepayer costs, and analysis of financial feasibility. Finally, the medium load scenario "preferred" portfolio was analyzed for price risk using a Monte Carlo simulation of electricity and gas prices.

PG&E assessed the financial feasibility of meeting the resource commitments using either 50% utility ownership or 100% contracts for new, conventional generation resources. The assessment compared projections of key credit ratios with benchmark ranges necessary to maintain or strengthen PG&E's current low investment grade credit ratings. The analysis concluded that all scenarios appear to be financially feasible, but the 100% contracting scenarios, particularly with high load growth, would make it difficult if not impossible for PG&E to improve its credit ratings.

Portfolios were constructed in a "bottoms-up" manner consistent with the EAP loading order. Beginning with the forecast of capacity and energy requirements for expected bundled customers (i.e., net of existing direct access (DA) and projected Community Choice Aggregation (CCA) and noncore load), losses for transmission and distribution and unaccounted for energy (UFE) were added to derive expected capacity and energy requirements. Funded energy efficiency (EE) programs and existing interruptible programs reduced these requirements. Existing resources including Utility-Retained Generation, Qualifying Facility (QF) contracts, California Department of Water Resources (DWR)-assigned resources, and other existing contracts were subtracted from the load to identify the Net Open Position (NOP).

The NOP was filled using the preferred resources identified in the EAP. PG&E first added reliable, cost-effective and attainable EE programs. Distributed generation was then added based on PG&E and California Energy Commission (CEC) forecasts. Next, state mandated programs were added to the portfolio, including Demand Response (DR) and renewable resources. Decision 03-06-032 requires that price-induced DR provide 5 percent of capacity requirements at time of system peak by 2007 and going forward through the planning horizon. A variety of renewable resources were then added to the portfolio to meet the RPS annual procurement target (APT) of an additional 1 percent of energy requirements met by these resources each year.

Finally, PG&E added conventional thermal resources to balance out the remainder of its capacity and energy requirements. Conventional thermal resources included contracts with existing resources and new and efficient dispatchable and peaking resources, which are both contracted and utility owned. PG&E's preferred resource plan assumes all new resources will be deliverable to load. As described in the Plan Implementation section (Section IV), PG&E intends to procure resources primarily through competitive solicitations, although certain resource opportunities of substantial benefit to its customers may materialize in other ways as well (for example, settlement of litigation).

PG&E's resource planning process incorporates transmission in an iterative process. This IRP assumed all existing and new transmission contained in its most recent CAISO-approved 2003 Electric Transmission Grid Expansion Plan., which includes all network reinforcements necessary to meet expected load and is expected to minimize CAISO Reliability Must Run (RMR) requirements in PG&E's service territory. The 2005 PG&E Electric Transmission Grid Expansion Plan will incorporate the procurement under this resource plan. This is consistent with I.00-11-001 in that the transmission plan is developed based on resources that have been identified.

b. Planning Assumptions

In developing the resource plan, PG&E developed and used assumptions appropriate for long term plan development. While there are many assumptions required in developing a long term plan, several driving assumptions are load forecast development, electricity and gas prices, QF contract resources, supply options, and transmission. These are discussed below.

i. **Load Forecast**: Consistent with the June 4 ACR, PG&E developed three hourly load forecasts to represent a realistic range of likely future operating requirements that the utility should reasonably plan for. The forecasts reflecting different levels of growth and bundled load departures used for portfolio development. PG&E provided an additional 16 forecasts as requested by the Commission in the June 4 ACR and clarified in the June 16 ALJ's Ruling.

PG&E's medium-load scenario energy and demand forecast is based on actual system load, escalated using internal forecasts for 2005 and 2006 and CEC IEPR projected growth rates thereafter and adjusted to account for possible CCA and noncore load departures. PG&E's adjustment for CCA and non-core load departures did not identify specific loads that may leave bundled service, rather assumed a portion of total load would leave. This method allows PG&E to plan appropriately. The high-load scenario assumes more optimistic load growth with less bundled customer departures. Conversely, the low-load scenario includes pessimistic assumptions regarding economic growth and assumers a higher level of bundled customer departures.

A significant uncertainty in the load forecasts is the potential migration of load from bundled service through Community Choice Aggregation (CCA) programs and due to a core/noncore market structure, both which are likely to occur during the planning horizon. PG&E believes it has made reasonable assumptions regarding these issues given the information available today, however, it cannot know what the legislature and the Commission will ultimately decide, nor the quantity of currently bundled load that may elect to participate in these programs.

ii. **Electricity and Gas Prices:** PG&E developed forecasts for electricity and gas prices based on the forward trading markets. These prices were based on April 19, 2004 forward market quotes, and are consistent with the prices PG&E used in other concurrent proceedings. PG&E uses the forward prices since they represent current market-based, opportunity costs, rather than estimates derived from conjectures about supply and demand conditions in the future.

iii. **QF Resources:** The June 4 ACR required the utilities to show current quantities of baseload QF purchases and plans for continuing to meet those needs. PG&E assumed that existing QFs under contract with PG&E would continue delivering capacity and energy consistent with historical deliveries. PG&E made no assumptions regarding the future of specific QF's with expiring contracts, rather it assumed that, in aggregate, 90% of all expiring QF energy and capacity would remain in operation and sell energy to PG&E for the plan term. PG&E assumed the remaining 10% would either sell to alternate suppliers or shut down after contract expiration.

PG&E proposes that QFs with expiring contracts could either participate in its procurement solicitations for multi-year contracts or could elect to continue selling capacity and energy to PG&E under an annual contract based on market prices. These contract options provide QF generators with expiring contracts an opportunity to continue selling to PG&E and comply with all PURPA requirements. PG&E made no assumption in its resource planning regarding the choices that individual QFs may make in the future.

iv. **Supply Resources Options:** PG&E developed a portfolio of potential resources available to meet its future requirements, including existing and new renewable and conventional generating resources. For existing resources PG&E developed assumptions on resource availability, cost, and characteristics based on its knowledge of current non-contracted resources in the market. For new conventional and renewable resource information it relied primarily on information published by the CEC as part of its Integrated Energy Policy Report.

III. Resource Plan

The medium-load scenario portfolio represents PG&E's best estimate of how it plans to meet the needs it expects and serves as PG&E's proposed resource plan. The low-load and high load case scenarios represent a bandwidth of potential outcomes depending on changes in assumptions, and PG&E developed portfolios for these scenarios as derivations of the medium load portfolio. PG&E used derivations of the medium load portfolio rather than develop new portfolios "whole-cloth" to ensure that the medium load portfolio was sufficiently robust and flexible to respond to changes in demand over time within the range of the three load scenarios.

Mindful of the significant uncertainties in the evolution of the market structure and the extent and timing of retail load departures to community aggregation and noncore service, PG&E proposes a plan that can be adjusted to respond to changing conditions within the range of three load scenarios yet, importantly, makes long-term commitments that can result in the development of the necessary new, cleaner and more efficient resources and which also meets minimum reliability needs. PG&E's plan vigorously fills our net open position to the maximum feasible extent with environmentally preferred resources, such as customer energy efficiency, demand response, and renewables.

a. IRP Medium Load Scenario Portfolio ("Preferred Portfolio")

PG&E's medium load scenario portfolio includes a host of resources that meets the resource adequacy target of 15-17% of peak demand, supports the State's Energy Action Plan loading order of resources, and contains a flexible mix of resources to meet customer demand and energy requirements. Under the plan PG&E will procure capacity and energy from energy efficiency programs, renewable resources and conventional generation, which may be either utility owned or contracted.

i. Energy Efficiency

PG&E's preferred portfolio includes all cost-effective and reliable energy efficiency programs, consistent with the EAP. The energy efficiency programs included in the plan provide for an aggressive ramp-up of multi-faceted programs in the residential, commercial and industrial markets, with total potential expenditures of approximately $1 billion over the 10-year planning horizon. As PG&E's net open needs are for peaking power in the near-term, initially new energy efficiency activities will focus on air and space cooling and lighting equipment. PG&E will aggressively target cost-effective energy savings during peak, off-peak and shoulder periods starting in 2007. PG&E proposed energy savings targets in its Prepared Testimony. The Commission adopted energy savings targets in the *Interim Opinion: Energy Savings Goals for Program Year 2006 and Beyond*, issued on September 29, 2004. The Commission's adopted targets are higher than PG&E's proposed targets. PG&E will prepare and file energy efficiency program plans for 2006 – 2008 that reflect the Commission's adopted targets.

ii. Other Demand Side Resources

PG&E expects a portion of its resource needs will be met by other demand side resources including price-induced demand response programs. These programs are assumed to meet 5% of PG&E's peak demand by 2007. The plan also anticipates distributed generation will further reduce resource needs.

iii. Renewable Resources

The preferred portfolio also includes sufficient renewable resources to meet RPS requirements. PG&E has proposed renewable resources based on their likely availability and value to the system, though actual procurement of renewable resources generation will occur based on "least-cost/best-fit" analysis of bids received through its proposed Renewable Procurement Plan and accompanying RFO for Renewable Resources, submitted to the CPUC on June 24, 2004 (R.04-04-026). Under the load assumptions of the Medium Load scenario, meeting the required 1 percent per year APT results in PG&E achieving the 20 percent RPS target in 2011. PG&E

performed a sensitivity analysis to evaluate achieving the 20 percent target in 2010. The additional wind resources added in the 2010 sensitivity are based on an assumption of QF contract restructurings to provide for repowering of a number of wind farms in the Altamont pass to upgrade to more efficient plants. This assumption is more easily evaluated than an assumption of a generic response to RPS solicitations. PG&E recently received approval of the contract for the repowering of the Buena Vista wind farm. Based on this initial outcome, PG&E assumes repowering of up to 400 MW of the almost 600 MW in the Altamont Wind Resource Area. There are several factors that can make wind repowerings favorable to ratepayers: the production is close to the load center, usually no additional transmission investment is needed, a higher gas-based SRAC price could be replaced by a lower fixed price, and the new output might have a better load profile than the former output. However, there is no guarantee that most existing Altamont facilities will be repowered. Alternatively, new wind facilities could also help meet this estimate, but without the additional benefits of a repowering.

To achieve the 20 percent target by 2010 if there is no CCA or non-core load loss, an additional 175 MW of baseload (e.g., geothermal or biomass) renewable resources would be required beyond that shown in the plan. Proposed Energy Efficiency and Renewable Procurement are summarized on Table 1 below.

Pacific Gas and Electric Company
New EE and Renewable Procurement by Year
Cumulative Purchases (MW)

Year	New Energy Efficiency[28]	RPS Compliance Renewables	Accelerated Renewables (Wind Repowering)	Total Nameplate Renewables	Reliable MW Renewables
2005	-	-	-	-	-
2006	503	200	100	300	204
2007	708	300	200	500	320
2008	936	550	200	750	596
2009	1168	700	400	1,100	722
2010	1388	900	400	1,300	891
2011	1624	1,150	400	1,550	1,017
2012	1878	1,300	400	1,700	1,045
2013	2156	1,500	400	1,900	1,174
2014		1,750	400	2,150	1,342

28 The energy efficiency targets are those adopted in D.04-09-060, Table 1A. They reflect savings from all energy efficiency – procurement-funded programs, public goods surcharge-funded programs and low-income programs. In its Prepared Testimony, the energy efficiency targets listed in Table 4-10 only included savings funded with 2006 and beyond procurement dollars. Furthermore, the energy savings targets the Commission adopted are "average peak savings" defined as average savings during the summer peak hours. D. 04-09-060, p. 29. In contrast, PG&E proposed coincident and non-coincident peak load reductions in Table 4-10 of its Prepared Testimony.

iii. Conventional Resources

The preferred portfolio includes a mix of conventional resources, including contracts of varying duration and utility owned generation, to meet the balance of its energy requirements. PG&E's primary need is for peaking/shaping resources, which is driven by two key underlying assumptions: (1) the assumed loss of baseload noncore load; and (2) the assumed addition of new baseload renewable resources, some of which operate intermittently.

PG&E proposes to fill these requirements using a variety of short- and medium-term transactions, and long term resources which may be either contracted or utility-owned. PG&E's strategy over the next four years is to contract with existing market resources under short to mid-term contracts. These contracts will ensure adequate supply in the period prior to when new generation facilities may come on-line. The short-term nature of these transactions will help to mitigate, but not eliminate uncertainties from load migration to other suppliers. For example, if participation in community aggregation is greater than anticipated, PG&E can allow a short-term transaction to expire and choose not to replace it or a medium-term transaction will be stranded for a shorter period than a long-term commitment.

The preferred portfolio included only as much long-term capacity as could be used to meet the low load scenario, with the remaining needs filled with short and medium-term contracts. By procuring less long-term resources, PG&E can minimize any stranded costs associated with long-term resource procurement should the low load scenario occur. The preferred plan includes procurement of long-term capacity beginning in 2007-2008, with additional needs in 2010. Given the level of uncertainty in the many assumed variables, anything beyond 2010 has too much conjecture to be actionable and should be re-evaluated in the 2006 plan.

b. Comparison of Medium Load Scenario Portfolio With Alternative Portfolios

In compliance with the June 4 ACR as modified by the June 16 ALJ Ruling, PG&E assumed three plausible cases out of the many possible variations. The medium load scenario is PG&E's best estimate of the needs it expects. As specified in the June 4 ACR, the high and low load scenarios are "reasonable guesses" but not extreme cases of what could happen to future utility load. PG&E designed the preferred portfolio to meet expected requirements under the medium load scenario.

Given the assumptions made on Demand Response, and CCA and noncore load migration there is a risk that procurement anticipated in the preferred portfolio may not be sufficient to meet actual requirements. Should there be less customer departure, higher load growth, or less Demand Response in the early years of the plan (up to 2010), PG&E would seek to contract with existing generation under short-term contracts to balance its requirements. Sustained above-expected loads after 2010 could be met by re-contracting with existing resources with expiring contracts or contracting with new resources. Conversely, if CCA or non-core departures are greater or if energy efficiency is more successful than assumed, short-term contracts would be allowed to expire when their terms are complete.

As stated above, PG&E believes that it is prudent to make long-term commitments based on its low load case with short and medium-term resources used to fill remaining needs. Lower load outcomes are possible, but it would not be prudent to plan for such extremes. Therefore, commitments made in the preferred portfolio should receive cost recovery assurance similar to that received by SCE (D.03-12-059) and SDG&E (D.04-06-011) for their recent commitments, i.e., "...all customers ... that are currently ineligible for direct access are obligated to pay for the stranded costs of any new generation for the next ten years."

IV. Plan Implementation

PG&E proposes to procure additional resources primarily through the use of competitive solicitations during 2004 and as needed in the future. This fall, PG&E will be initiating a series of Requests for Offers (RFO) for new resources to fulfill its long-term resource needs. In keeping with the loading order in the state's EAP, PG&E will aggressively pursue procurement of customer energy efficiency, demand response and renewables, will continue to support and interconnect distributed generation consistent with existing programs and tariffs, and will encourage innovative proposals that meet its resource portfolio needs in a cost-effective manner. PG&E estimates that its plan will result in the avoidance of 29 million tons of carbon dioxide emissions compared to conventional alternatives. PG&E's proposal will help to keep California the nation's leader in reducing carbon emissions.

In order to reduce stranded costs and potential cost shifting, PG&E proposes to move ahead today only with those short-term and mid-term commitments believed to be necessary and cost-effective consistent with the medium load scenario. For the same reason, PG&E proposes to solicit only the long-term commitments that are consistent with the Low Load Scenario. However, the actual amount of noncore and CCA customers and the timing of departure from bundled service are admittedly difficult to forecast at this time and the stranded cost and cost shifting risks cannot be fully mitigated even under this approach. Therefore, PG&E's commitments must be, conditioned upon assurances from the California Public Utilities Commission (CPUC or Commission) that the costs of these new commitments will be recoverable under a non-bypassable charge from all customers, including those that elect to take generation services from another supplier, such as a local publicly owned electric utility (as defined in Section 9604(d)), or consistent with community aggregation and noncore options.

a. Renewable Resource Solicitation

On July 15, 2004, PG&E issued its Renewable Portfolio Standard (RPS) solicitation and PG&E anticipates signing contracts with eligible renewable generators by the end of 2004. PG&E hopes to receive competitive bids for renewable generation that would allow it to surpass the minimum target for incremental renewable energy, 1 percent of retail load, and reach the mandated 20 percent level by 2010 under the Medium Load Scenario in its LTP.

b. Energy Efficiency Solicitation

PG&E will issue multiple RFP for third-party energy efficiency programs. Consistent with the multi-party "Reaching New Heights" proposal filed in the Energy Efficiency OIR 01-08-028, at least 20 percent of the program funds will be implemented by third parties selected through this competitive process.

c. Conventional Resource Solicitations

Short-Term/Mid-Term Commitments: PG&E's strategy over the next four years is to contract with existing market resources under short to mid-term contracts. These contracts will ensure adequate supply in the period prior to when new generation facilities come on-line. The short-term nature of these new transactions will help to mitigate, but not eliminate uncertainties from load migration to other suppliers. For example, if participation in community aggregation is greater than anticipated, PG&E can allow a short-term transaction to expire and chose not to replace it or a medium-term transaction will be stranded for a shorter period than a long-term commitment.

PG&E requests immediate authority from the Commission to execute the short-term and mid-term commitments under its existing short-term procurement plan. (PG&E has filed a petition to modify that would grant five-year contracting authority for these purposes.) PG&E needs flexibility to cost-effectively fill out its mid-term portfolio over time and when conditions are most favorable. The long-term plan proceeding is not an appropriate forum for review and approval of such mid-term transactions. PG&E therefore requests that the Commission either grant its petition for modification of the short-term procurement plan decision and grant PG&E five-year contract authority or otherwise provide such authority in this proceeding.

Long Term Commitments: PG&E will issue two separate RFOs this fall for new peaking, shaping, and dispatchable generation. One RFO will solicit proposals for utility-owned generation and one RFO will solicit resources that would be purchased under long-term contracts. PG&E's target for long-term commitments over the 10-year planning horizon is to achieve 50 percent utility ownership and 50 percent long-term contracts. This will foster the hybrid market model endorsed by the Commission in recent resource decisions by providing new opportunities for the merchant generation sector while ensuring a measure of financial and operational stability through utility ownership. Importantly, the 50/50 approach is also designed to help reduce debt equivalence impacts as compared to a 100 percent power purchase contracts strategy. PG&E intends to focus on its residual needs for the period 2008 to 2010 in this first round of RFOs.

For utility-owned projects, PG&E will request bids from developers. The projects would be subject to cost of service ratemaking. For ratemaking purposes, PG&E will ask the Commission at the time of approval of the RFO results to adopt a reasonable cost for the facility to be placed in rate base and, to the extent that actual costs of construction are less than or equal to such reasonable cost, no after-the-fact reasonableness review would be required. PG&E will also propose recovery mechanisms for ongoing costs.

PG&E anticipates issuing the two RFOs in October and receiving bids near the end of the year. Following the issuance of the LTP decision, PG&E will address any Commission-ordered changes or modifications to its plan, consult with its Procurement Review Group and will file a compliance filing seeking pre-approval of its proposed winning bidders. In conjunction with such filing, PG&E will assess the cumulative debt equivalence impacts of the proposed winning bids by applying the methodology described in its testimony in this proceeding and also the cost of capital proceeding. In addition PG&E requires that the Commission determine the debt equivalent impact from all signed contract in this solicitation, and that this value be noted for consideration in the appropriate Cost of Capital proceeding. PG&E requests that the Commission review the bids on an expedited basis and issue a decision no later than the second quarter of 2005.

d. Unique Resource Opportunities

PG&E recognizes that certain resource opportunities that may be of substantial benefit to its customers may arise from time to time where timing constraints may require their evaluation by the Commission on a separate, expedited track. For example, in connection with settlement of litigation, certain resources may become available at attractive prices. If these opportunities materialize, PG&E will seek separate approval from the Commission.

V. Plan Approval

PG&E requests that the Commission approve its proposed long-term plan and authorize PG&E to proceed with implementation of the plan as specified herein.

Summary of Southern California Edison Company's (U 338-E) Long-Term Procurement Plan

SUMMARY OF SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) LONG-TERM PROCUREMENT PLAN

Southern California Edison Company (SCE) requests that its 2004 Long-Term Procurement Plan (LTPP) be adopted as the basis for evaluation and approval of future procurement activities. Overall, SCE's plan is to minimize its bundled customers' financial risks by committing only to short- and medium-term, peaking and intermediate resources. Additionally, SCE requests changes to its Existing AB 57 Procurement Plan (Existing AB 57 PP); a new Demand-Side Management proposal; policy findings on demand-side management, debt equivalence and customer base stability.

I.

SUMMARY OF REQUESTED CHANGES TO AB 57 PROCUREMENT PLAN

SCE's LTPP proposes that SCE's Existing AB 57 PP, authorized by the Commission in Decision No. 03-12-062, be modified as set forth below. Acceptance of SCE's revisions will eventually allow SCE to transact on a forward basis up to five years in term for nonrenewable resources to the extent that debt equivalence issues are resolved satisfactorily.[1]

Updated Electrical Capacity Limits. SCE proposes that its revised electrical capacity position limit be set annually to equal the difference between a 117% planning reserve level and SCE's current capacity position, including California Department of Water Resources (DWR) contracts allocated to SCE's customers.

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1 Note however that SCE will not initially consider terms in excess of three years for non renewable resources due to debt equivalence limitations.

This modified limit will allow SCE to procure resources needed to meet any resource adequacy requirement (RAR).[2]

Updated Rate-of-Transaction Limits for Electrical Capacity. Adopt rate of transaction limits that reflect the revised annual electrical capacity limits set forth above, and that reflect SCE's need to secure electrical capacity to meet an RAR.

Updated Limits Contained In SCE's Existing AB 57 PP. SCE will update all limits[3] in its Existing AB 57 PP (except those related to electrical capacity procurement) using the methodologies previously utilized in the Existing AB 57 PP.[4]

Other Modification To D.03-12-062 Are Necessary For Clarity And To Eliminate Unnecessary Requirements. SCE's petition for modification (PFM) of D.03-12-062 raised several issues that requires clarification. If that PFM is not acted on before the decision in this proceeding, SCE requests that the outstanding issues raised therein be resolved here. Accordingly, SCE requests:

- Specific timing for approval of the IOUs compliance filings or a statement that the absence of resolution after a defined length of time (90 days) forecloses the opportunity for further review and establishes eligibility for cost recovery;
- A specific statement that the target guideline for spot market purchases does not apply to procurement of capacity to meet WECC operating reserve requirements;

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2 To the extent the Commission does not adopt a specific load and supply scenario, SCE will use its LTPP medium case load and supply scenario to calculate its updated annual electrical capacity position limits.

3 These include position limits for SCE's forward electrical energy and natural gas sales and purchases, as well as SCE's electric transmission and natural gas pipeline and storage capacity transactions.

4 Unless otherwise instructed by the Commission, SCE will use the medium case load and resource scenarios from its LTPP to update its limits.

- Deletion of language that could be interpreted to allow DWR to perform "after-the-fact reasonableness reviews";
- Changing of language requiring IOUs to consult with their procurement review groups (PRGs) for transactions greater than 90 days, to a requirement that IOUs consult with their PRGs for transactions greater than one calendar quarter (92 days);
- Modification of language directing SCE to assume a "pro rata" allocation of DWR costs. Such language should be replaced with the seven-step process outlined by SCE for treatment of DWR contracts.
- Permission for IOUs to enter into contracts of up to five years in length where delivery begins in 2004 or later and termination occurs prior to 2009;
- Modification of language lowering the "unqualified certification" basis for authorization of SCE's proprietary risk model;
- Modification of language restricting bilateral transactions to less than one calendar quarter in length and clarify that the term "less than 90 days forward refers to the start date of the transaction";
- Elimination of requirement that SCE demonstrate that identified over-the-counter (OTC) brokers provide prices equivalent to those of exchanges;
- Clarification of how to measure the level of TeVaR which triggers a PRG meeting;
- Deletion of the sentence stating that a utility should not "arbitrage" in energy markets; and
- Clarification that SCE's compliance filing is due at the same time as those of Pacific Gas and Electric Company and San Diego Gas and Electric.

Modification to the Application of SCE's Existing AB 57 PP Portfolio Risk Screen. SCE proposes to revise the application of the Existing AB 57 PP portfolio risk screens. At a minimum SCE proposes that the portfolio risk screen threshold should not be applied to potential transactions that conclude delivery in three years or less, as measured beginning in the first month following the month in which the transaction is executed.

SCE's Existing AB 57 PP Should Be Modified To Become A Rolling Five-Year Procurement Plan. SCE's Existing AB 57 PP was designed to allow transactions through December 31, 2008. SCE proposes revision of the five year fixed term feature of its Existing AB 57 PP to become a rolling five-year term (i.e., it would be effective on an a forward 60-month evergreen basis, until the plan is superseded by a subsequent procurement plan).

Debt Equivalence Issues Must Be Resolved Before SCE Can Consider Contracts In Excess of Three Years. SCE proposes to limit its forward transactions for nonrenewable resources to terms of three years or less, until the Commission satisfactorily addresses debt equivalence. SCE will provide written notification to the Commission's Energy Division at such time as SCE believes the debt equivalence issue has been satisfactorily resolved. This notification will indicate that SCE will consider forward contract terms for nonrenewable resources up to five years in duration, but that SCE will not be required to contract up to five years in duration.

Clarification of Authorized Procurement Product. SCE proposes to make two slight changes to the Authorized Procurement Product table (Table IV-1) in the Existing AB 57 PP to clarify the use of products with index based prices. Specifically, the changes will authorize SCE to conduct transactions of Forward Spot Energy (Day-ahead and hour-ahead purchases, sales, or exchanges) at either set prices or at index-based prices.

II.

SUMMARY OF SCE'S DEMAND RESPONSE REQUEST

SCE's LTPP proposes to aggressively increase the amount of Demand-Side Management (DSM) SCE provides with its Advanced Load Control Program (ALC). This proposal will yield 700 MW of peak load reduction by the end of a seven-year deployment beginning in 2005. The average cost of this program will be $42 million per year.[5] Under this program, new digital and programmable thermostats with modified dispatch strategies will be deployed to increase customers' comfort options, while providing dispatchable demand reduction program. SCE proposes to target about 500,000 residential customers with this program over a seven year period.

The ALC program would provide for:

- ALC resources to be called upon in less than 10 minutes;
- A "price responsive" program which would be triggered by utility procurement /market prices; SCE plans to trigger the program 50 hours each year on such a basis, and 30 hours for reliability dispatch;
- Load control devices that are addressable so that they can be activated by dispatchers in MW blocks and by geographic district;
- Implementation of a program with no required up-front investment;
- Program cost of below the $85/kW-yr. threshold established in R.02-06-011;
- A minimum "usage" requirement screen;
- A voice override feature provided at an additional cost.

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[5] SCE proposes to continue other currently authorized Demand Response programs at the levels currently authorized by the Commission.

III.

SUMMARY OF SCE'S REQUESTED STATEMENTS REGARDING CERTAIN COMMISSION POLICIES

SCE's LTPP asks the Commission to make a number of policy statements regarding various issues. SCE sets forth its positions below.

Demand-Side Management and Energy Efficiency. SCE does not believe that its requested DSM program and its already existing energy efficiency programs can be fully successful without resolution of four policy issues. Accordingly, SCE requests that the Commission (a) extend demand response and energy efficiency planning cycles to coordinate with program funding cycles; (b) refine goals for price-responsive programs set forth in R.02-06-001, to include consideration of all program types (including reliability-based programs, information and customer awareness campaigns, and economics-triggered programs); (c) support utility administration of energy efficiency programs so that IOUs can rely on forecasted demand-side resources at levels envisioned by California's energy agencies; and (d) support performance incentives in furtherance of the Energy Action Plan's conservation and efficiency goals.

Expiring QF Contracts. SCE asks the Commission to defer policy issues surrounding such contracts to the Avoided Cost Proceeding (R.04-04-025).

Debt Equivalence and Collateral Requirements. SCE details the impact of debt equivalence on procurement and asks the Commission to recognize the impact of this issue on long-term contracts, and address that effect in the Cost of Capital proceeding. Similarly, SCE requests that the Commission recognize the impact of two changes to financial accounting standards (EITF Issue No. 01-08 and FIN 46 (R)) that may affect IOUs' costs of contracting for power.

Customer Base Instability. In order to safeguard SCE's bundled service customers, the Commission must temper the ability of customers to switch between bundled service and Direct Access service; adopt appropriate exit fees for municipalization and community choice aggregation; and ensure that RARs are equally applied to all LSEs.

IV.

SUMMARY OF GUIDELINES FOR FUTURE PROCUREMENT FOUND IN SCE'S LONG-TERM PROCUREMENT PLAN

In addition to the specific issues outlined above, SCE asks the Commission to adopt SCE's LTPP as the basis for evaluation and approval of future procurement activities that fall under the LTPP. Specifically, SCE seeks approval of its strategy in the following areas.

- Resource Commitments. SCE's current supply portfolio is dominated by long-term and baseload resource commitments. Such a portfolio results in SCE having excess supply that must be sold into the market. SCE seeks to minimize the financial risk of such resources to bundled customers by committing only to short- and medium-term, peaking and intermediate resources.[6] The multiple scenarios SCE presented in its LTPP all indicated that SCE would follow this strategic path forward, regardless of changes to its load. Accordingly, all of the plan scenarios presented in SCE's LTPP envision filling SCE's needs with short- and medium-term, peaking and intermediate resources.
- Debt Equivalence. Going forward, SCE intends to include debt equivalence costs in its assessments of procurement alternatives of greater than three years on an ongoing basis, both for assessing

[6] Given the wide array of outcomes related to core/non-core and Community Choice Aggregation, SCE's 2004 LTPP therefore includes no new long-term commitments, other than those necessary to meet RPS requirements.

aggregate procurement plans and for determining which individual resources satisfy SCE's requirements at the lowest cost. SCE's LTPP included the formula SCE intended to use to calculate such costs.

- Financial Accounting Changes. As with debt equivalence, SCE intends to include additional costs ascribed by changes in financial accounting standards described in its testimony when assessing aggregate procurement plans and for determining which individual resources satisfy SCE's requirements at the lowest cost.
- Collateral Requirements. At present, SCE's Existing AB 57 PP includes sufficient collateral capacity for the near term. SCE's ability to stay within such limits will depend heavily upon the length of new contracts signed to meet resource needs. If changing resource requirements lead to higher collateral levels, SCE will request to amend its Existing AB 57 PP to support the additional capacity requirements.
- QF Contracts. SCE has eight QF contracts that are scheduled to terminate prior to December 31, 2005. SCE will offer each of these QFs a five-year SO1 contract commencing on the termination date of their respective contracts, in accordance with D.04-01-050. Additionally, as to two QF contracts, whose termination dates have been extended through December 31, 2004, SCE will offer each of these QFs additional four-year terms under SO1 contract pricing. SCE further reserves the right to comply with PURPA requirements through additional options such as bilateral negotiations and competitive solicitations, in accordance with Decision No. 03-12-062.

Summary of SDG&E's

Long-Term Resource Plan

ATTACHMENT A

SUMMARY OF SDG&E'S LONG-TERM RESOURCE PLAN

The objective of SDG&E's long-term planning process is to provide reliable electric supply to customers at the lowest possible cost and volatility risk, while meeting the State's objectives regarding the preferred loading order for resources. In order to accomplish these goals, SDG&E's long-term plan addresses not only additional demand and supply side resources, but also major transmission lines needed to meet grid reliability criteria, and it also makes recommendations for an integrated balance of each of these resource types. SDG&E's long-term plan provides the three resource scenarios specified in the Assigned Commissioner's June 4, 2004, Ruling and Scoping Memo (ACR), and recommends its medium load plan for Commission approval.

In designing its three resource planning scenarios, SDG&E attempted to accomplish a number of objectives, including meeting the ISO's grid reliability criteria and designing each scenario to meet a planning reserve margin of 15%-17% by 2006. The reserve margin SDG&E used is based on the bundled load SDG&E serves, as directed by the Commission in D.04-01-050. Due to the fixed size of individual resources and other policy objectives, reserve margins in SDG&E's plan will fluctuate around a target as resources are added, and may slightly exceed the targeted reserve in some years. This circumstance is more problematic for SDG&E than the other electric IOUs due to SDG&E's relatively smaller size. As an example, adding a typical size 50 MW combustion turbine to SDG&E's system would impact reserves by over 1%, as compared to SCE and PG&E where the same size unit would impact reserves by about a quarter of a percent.

Resources were added in SDG&E's plan according to the Commission's preferred loading order. First, SDG&E reduced the forecasted load by expected levels of cost-effective energy efficiency and distributed generation. Second, demand reduction programs were added to further reduce the resource need. Third, renewable power was added to meet an accelerated Renewable Portfolio Standard (RPS) target of 20% of energy needs by 2010. Finally, conventional resources were added to meet the remaining need. SDG&E tailored resource additions so that in combination with the existing resources, the resource mix includes a combination of base loaded, intermediate and peaking resources to meet the overall load shape of SDG&E's customers.

The results presented in its long-term plan provide the basis for SDG&E's request that the Commission endorse a long-term sequence of resource types, sizes, and timing that will guide SDG&E's activities to bring specific, conforming resource proposals to the Commission for approval in coming years. While changing circumstances and/or more detailed analysis accompanying specific resource additions will be reflected as necessary in the future, it is expected that Commission approval of SDG&E's medium load plan in this proceeding will serve as the essential first step in SDG&E's further development of specific resource proposals in coming years. In the event that larger scale changes are needed to the overall plan due to significant changes in key drivers (such as availability and cost of resources), these modifications will be included in future updates to the long-term plan and subsequent implementation processes.

SDG&E's resource plan also calls for additional local transmission and a new 500 kV line in 2010 under the medium load plan, pursuant to SDG&E's balanced portfolio strategy and to ensure grid reliability. Once this needed transmission is in place in 2010, the remaining four years of the plan lay out a strategy to replace the expiring DWR contracts and meet continuing load growth after cost-effective energy efficiency and demand response programs have been implemented. These resource needs will be met by continuing to pursue renewable power beyond the 20% target, adding on-system generation to provide needed energy and capacity as well as to address local area reliability, and adding an additional increment of generation that may be on- or off-system depending on price and availability at the time.

SDG&E's three (medium, high, and low) resource plan scenarios illustrate how the plan will react given the load uncertainty SDG&E faces with the possible implementation of a core/noncore structure and Community Choice Aggregation (CCA). The base case, or medium load plan scenario, is SDG&E's preferred plan, which represents SDG&E's best estimate of the resources needed to reliably serve its customers. Similar to last year's filing, this resource plan follows the Commission's adopted loading order and also relies on a mix of new transmission and in-service area resources as the best integrated balance for SDG&E's service area. It shows no loss of load to a core/noncore split or CCA. SDG&E used this load scenario so that the Commission will have a resource plan illustrating what is needed during the ten-year planning horizon based on what is known today about future load departure. Given the uncertainty surrounding the timing and magnitude of emerging rules for CCA and direct access and the potential resulting outcomes, this is the plan SDG&E believes it is most likely going to have to serve.

In this plan, reserve margins assume a ramp-up in 2005, but then target a minimum of 15% for 2006 – 2014. Efforts to achieve 20% of the energy mix by 2010 from renewable power will mean SDG&E will primarily procure only renewable power until 2010. SDG&E will assess the timing and costs of renewable power in the renewables RFP that was issued on July 1, 2004. The medium load plan also assumes that new transmission capability is added in 2010 to address grid reliability and load pocket issues. This additional transmission also helps reduce the need for RMR units and is anticipated to provide access to additional renewable sources that SDG&E shows coming into its plan in 2011-2014.

Beginning in 2011, SDG&E will add a combination of resource types to replace the expiring DWR contracts and potentially to replace retirement of aging local generation currently providing RMR, if necessary. The majority of the resource additions are predicted to be from on-system resources to maintain grid reliability and further reduce RMR costs. The resources considered include distributed generation, existing generation facilities, repowered facilities or new facilities. Through the combination of transmission additions and local generation committed to SDG&E, the medium load plan ultimately eliminates the need for additional resources to be procured for RMR.

SDG&E's high load scenario shows how SDG&E would adjust its plan to serve a higher bundled load occurring along with some additional departing load to direct access. The higher load is the result of stronger economic growth, but it is somewhat mitigated by the additional customers being served by other providers. Under this case, additional renewable resources are needed to meet the 20% goal. In order to meet grid reliability, this case adds the same transmission as was added in the base case plus additional on-system resources. This plan is similar to the medium load plan with additional resources needed to meet a higher load. In the 2006 – 2010 timeframe, additional renewable power is procured to meet the increased load and to meet the 20% goal. Also, additional on-system resources are procured in 2007-2010 to reduce RMR costs. In the 2011 – 2014 timeframe, the higher load is served with additional renewable power to achieve the same percentage as in the base case, and with additional peaking to intermediate resources, the majority of which are on-system to meet grid reliability and reduce RMR costs. In this case, the plan was able to respond to higher loads with little price change. The higher fixed costs are partially attributed to higher RMR capacity costs. The higher peak requires more RMR units be retained to meet local grid reliability needs. The high load scenario shows that SDG&E's plan can address a higher than expected load through the addition of relatively small amounts of generation beyond that added in the medium load plan. The high case also further illustrates the value of having the additional transmission proposed for 2010, since this additional capacity helps address grid reliability concerns should local generation be slowed in its development.

The low load scenario shows what can happen should there be aggressive departures due to core/noncore and CCA, with subsequent significant migration of load to these options in a relatively short period of time. In this scenario, SDG&E has also assumed that it would still be required to meet 20% of its energy needs from renewable power in 2010, even though it did not need the associated capacity to meet reserves. This case also includes the additional transmission as in the other cases to meet grid reliability. SDG&E will add fewer resources in this case due to smaller bundled load than in the base case. Under this scenario, SDG&E would not need any resource additions through 2010. However, for this scenario SDG&E has assumed that it would still be required to meet the 20% renewable energy target by 2010. Non-renewable resources would not be needed until 2011 as CDWR contracts expire. SDG&E would then add in-basin resources to meet the resource requirement and reduce RMR costs.

Although total load is lower in this scenario due to slower economic growth, total load in the region continues to grow. Because SDG&E has no need for additional resources to generate power to serve its customers, and assuming a CCA does not build local generation thereby contributing to grid reliability, additional transmission is still needed to maintain grid reliability. This case also results in the greatest need for RMR units. This result occurs because even though the overall load is lower than other cases (which reduces the total grid reliability need), SDG&E's small incremental resource needs limit the ability to reduce RMR through adding local generation, as would occur in the medium load base case and high load cases.

The high costs in SDG&E's low load scenario show how uncoordinated implementation of core/noncore and CCA can create costs. The case also shows that although additional economic sales may be made with the excess power, they are not likely to fully offset the cost of the surplus capacity. Some of these higher costs would be allocated across all customers for grid reliability and some costs would need to be allocated to CCA customers to prevent any cost shifting.

SDG&E's three resource scenarios were modeled utilizing Henwood Energy's RiskSym model in order to determine production costs. Each scenario was modeled under load, fuel and market price uncertainty, which was allowed to vary based on historical volatility. This allowed for comparisons both in terms of expected value and also showing the potential range of outcomes given load and pricing uncertainty. Each scenario was then evaluated by assessing a number of value measures, including total costs to customers, and implications caused by the load uncertainty.

The medium load plan shows that SDG&E is well positioned to meet its service territory's needs over the ten-year planning horizon and beyond. This preferred plan is able to focus almost entirely on renewable additions through 2010 because the conventional resources needed to ensure grid reliability in the period have been secured through the recently-approved SDG&E grid reliability RFP.

SDG&E's transmission analysis is also based on high, medium and low load forecasts. It assumes all the existing local and planned generation described above remain in service throughout the planning horizon, with the exception of the South Bay Power Plant, which SDG&E assumes will retire in the end of 2009 when the lease expires. Assuming the retirement of the South Bay Power Plant provides a conservative planning assumption, ensuring that SDG&E's plans can meet the region's needs given this uncertainty. The retirement of any other of the existing generation would cause the grid reliability need to increase by an amount equal to the additional capacity retired.

The medium load scenario demonstrates that SDG&E's grid reliability deficiency is 215 MW in 2010. SDG&E believes that the addition of a 500 kV interconnection is the best alternative to meet this grid reliability deficiency, providing at least 500 MW of increased non-simultaneous import limit (NSIL). Under the high load scenario, a 659 MW deficiency in 2010 exists, with the potential need for another major transmission upgrade as early as 2011 assuming no new generation is added during the 2010 to 2014 window. The low load scenario shows the first grid reliability deficiency in 2012. In this scenario, although not needed for grid reliability between 2010 and 2012, the line could still provide value since it would increase system wide reliability, provide for better energy access, and reduce the need for RMR units in the San Diego area.

A new 500 kV transmission line would provide a variety of benefits. Among them would be greater reliability, improved access to potentially lower cost, fuel diverse resources, allowing SDG&E to meet its 2010 renewables target, improved statewide grid reliability, reduction in RMR need, and reduced congestion costs.

The electric grid in California must be planned to accommodate a reasonable range of scenarios, and all of SDG&E's possible future load scenarios support the need for a new 500 kV transmission line beginning as early as 2010. Even in the low load scenario, a grid reliability deficiency is identified starting in 2012. Given that a new 500 kV line would provide additional statewide reliability for better energy access, reduce the need for RMR units in the San Diego area, and provide a reliability safety net for the uncertain timing of the transmission siting regulatory process, SDG&E believes that even this low load scenario requires SDG&E to continue the work needed to plan and receive Commission approval for a major 500 kV transmission expansion.

Currently, SDG&E has two conceptual configurations for an additional 500 kV transmission line that would provide benefits:

1. A 500 kV transmission line interconnecting SDG&E's Imperial Valley substation with a substation interconnected to the existing SDG&E 230 kV transmission grid. This alternative will generally follow an East-West direction and would involve termination at the western end with a 500/230 kV transformation to accommodate the injection of power flow into SDG&E's transmission system. It is expected that this configuration will provide substantial increases in both SIL and NSIL import levels. It is estimated that this alternative will be approximately 85 to 150 miles long with a conceptual cost[317/] of $650 million.

317/ These costs estimates are highly conceptual and do not include O&M costs. When SDG&E determines a final plan of service for the proposed 500 kV transmission expansion detailed cost estimates will be developed.

2. A 500 kV transmission line interconnecting SCE's 500 kV system with a substation interconnected to the existing SDG&E 230 kV transmission grid as proposed by the Lake Elsinore Municipal Water District for its Lake Elsinore Pumped Storage Project (LEAPS). This alternative will generally follow a North-South direction and would include termination at the southern end with a 500/230 kV transformation to accommodate the expected current injection of flows into SDG&E's transmission system. It is expected that this configuration will provide substantial increases in both SIL and NSIL import levels. This alternative is estimated to be approximately 35 to 50 miles long with a conceptual cost of $450 million.

An increase in SDG&E's NSIL of 500 MW, from 2500 to 3000 MW, and an increase in SIL level of 750 MW, from 2850 MW to 3600 MW, could conservatively be achieved with the addition of either of these lines. A combination of both of these transmission projects would provide additional increased import capability to San Diego, meet the CAISO's long-term goal to further develop the backbone 500 kV transmission system, and provide increased transfer capabilities allowing on-system resources to off-system market customers and may prove to be the best long-term alternative for ratepayers.